

§ 250.616

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with the tree in place and performed through the wellhead inside of conventional tubing using small-diameter jointed pipe (usually $\frac{3}{4}$ inch to $1\frac{1}{4}$ inch) as a work string, i.e., small-tubing operations, shall include the following:

- (1) Two sets of pipe rams, and
- (2) One set of blind rams.

(e) The minimum BOP-system components for well-workover operations with the tree in place and performed by manipulating spooled, nonjointed pipe through the wellhead, i.e., coiled-tubing operations, shall include the following:

- (1) One set of pipe rams hydraulically operated,
- (2) One two-way slip assembly hydraulically operated,
- (3) One pipe-cutter assembly hydraulically operated,
- (4) One set of blind rams hydraulically operated,
- (5) One pipe-stripper assembly, and
- (6) One spool with side outlets.

(f) The minimum BOP-system components for well-workover operations with the tree in place and performed by moving tubing or drill pipe in or out of a well under pressure utilizing equipment specifically designed for that purpose, i.e., snubbing operations, shall include the following:

- (1) One set of pipe rams hydraulically operated, and
- (2) Two sets of stripper-type pipe rams hydraulically operated with spacer spool.

(g) An inside BOP or a spring-loaded, back-pressure safety valve and an essentially full-opening, work-string safety valve in the open position shall be maintained on the rig floor at all times during well-workover operations when the tree is removed or during well-workover operations with the tree installed and using small tubing as the work string. A wrench to fit the work-string safety valve shall be readily available. Proper connections shall be readily available for inserting valves in the work string. The full-opening safety valve is not required for coiled tubing or snubbing operations.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 58 FR 49928, Sept. 24, 1993. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.616 Blowout preventer system testing, records, and drills.

(a) Prior to conducting high-pressure tests, all BOP system components shall be successfully tested to a low pressure of 200 to 300 psi. Ram-type BOP's, related control equipment, including the choke and kill manifolds, and safety valves shall be successfully tested to the rated working pressure of the BOP equipment or as otherwise approved by the District Supervisor. Variable bore rams shall be pressure-tested against all sizes of drill pipe in the well excluding drill collars. Surface BOP systems shall be pressure tested with water. The annular-type BOP shall be successfully tested at 70 percent of its rated working pressure or as otherwise approved by the District Supervisor. Each valve in the choke and kill manifolds shall be successfully, sequentially pressure tested to the ram-type BOP test pressure.

(b) The BOP systems shall be tested at the following times:

- (1) When installed;

(2) At least every 7 days, alternating between control stations and at staggered intervals to allow each crew to operate the equipment. If either control system is not functional, further operations shall be suspended until the nonfunctional, system is operable. The test every 7 days is not required for blind or blind-shear rams. The blind or blind-shear rams shall be tested at least once every 30 days during operation. A longer period between blowout preventer tests is allowed when there is a stuck pipe or pressure-control operation and remedial efforts are being performed. The tests shall be conducted as soon as possible and before normal operations resume. The reason for postponing testing shall be entered into the operations log.

(3) Following repairs that require disconnecting a pressure seal in the assembly, the affected seal will be pressure tested.

(c) All personnel engaged in well-workover operations shall participate in a weekly BOP drill to familiarize crew members with appropriate safety measures.

(d) The lessee shall record pressure conditions during BOP tests on pressure charts, unless otherwise approved

by the District Supervisor. The test interval for each BOP component tested shall be sufficient to demonstrate that the component is effectively holding pressure. The charts shall be certified as correct by the operator's representative at the facility.

(e) The time, date, and results of all pressure tests, actuations, inspections, and crew drills of the BOP system, system components, and marine risers shall be recorded in the operations log. The BOP tests shall be documented in accordance with the following:

(1) The documentation shall indicate the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. As an alternate, the documentation in the operations log may reference a BOP test plan that contains the required information and is retained on file at the facility.

(2) The control station used during the test shall be identified in the operations log. For a subsea system, the pod used during the test shall be identified in the operations log.

(3) Any problems or irregularities observed during BOP and auxiliary equipment testing and any actions taken to remedy such problems or irregularities shall be noted in the operations log.

(4) Documentation required to be entered in the operation log may instead be referenced in the operations log. All records including pressure charts, operations log, and referenced documents pertaining to BOP tests, actuations, and inspections, shall be available for MMS review at the facility for the duration of well-workover activity. Following completion of the well-workover activity, all such records shall be retained for a period of 2 years at the facility, at the lessee's filed office nearest the OCS facility, or at another location conveniently available to the District Supervisor.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 56 FR 1915, Jan. 18, 1991. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.617 Tubing and wellhead equipment.

The lessee shall comply with the following requirements during well-

workover operations with the tree removed:

(a) No tubing string shall be placed in service or continue to be used unless such tubing string has the necessary strength and pressure integrity and is otherwise suitable for its intended use.

(b) In the event of prolonged operations such as milling, fishing, jarring, or washing over that could damage the casing, the casing shall be pressure tested, calipered, or otherwise evaluated every 30 days and the results submitted to the District Supervisor.

(c) When reinstalling the tree, the wellhead shall be equipped so that all annuli can be monitored for sustained pressure. If sustained casing pressure is observed on a well, the lessee shall immediately notify the District Supervisor.

(d) Wellhead, tree, and related equipment shall have a pressure rating greater than the shut-in tubing pressure and shall be designed, installed, used, maintained, and tested so as to achieve and maintain pressure control. The tree shall be equipped with a minimum of one master valve and one surface safety valve in the vertical run of the tree when it is reinstalled.

(e) Subsurface safety equipment shall be installed, maintained, and tested in compliance with § 250.801 of this part.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 55 FR 47753, Nov. 15, 1990. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

§ 250.618 Wireline operations.

The lessee shall comply with the following requirements during routine, as defined in § 250.601 of this part, and nonroutine wireline workover operations:

(a) Wireline operations shall be conducted so as to minimize leakage of well fluids. Any leakage that does occur shall be contained to prevent pollution.

(b) All wireline perforating operations and all other wireline operations where communication exists between the completed hydrocarbon-bearing zone(s) and the wellbore shall use a lubricator assembly containing at least one wireline valve.